Open Inquires

Closed Inquires

Applicability

Question: Subject: Salt water disposal facilities

Any guidance on whether these are applicable to OOOOa Fugitive Emissions IR camera inspections

Answer: Yes, salt water disposal wells are subject to OOOOa fugitive emissions monitoring. Well is defined at 60.5430a as "a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected." Further, the definition of a well site includes injection wells (see 60.5430a, "Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well"). If you have any site specific information that we should consider, please feel free to send that as well and we can provide additional guidance. As a reminder, this is only for guidance purposes and does not constitute a formal determination of applicability.

Question: Follow on question:

Are salt water disposal wells subject to fugitive monitoring and/or tank standards under OOOOa? A review of the rule would indicate that they would be subject to fugitive monitoring; however, it is unclear if disposal fall under the purview of this rule. For example, if a third party were to receive water from a producer and were not engaged in the production of oil or gas, would they be subject to this rule. As a logical extension of that, then, would a producer's salt water disposal wells be subject? I have provided excerpts from the rule that are relevant.

60.5397a: For **each affected facility under §60.5365a(i)** and (j), you must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions by complying with the requirements of paragraphs (a) through (j) of this section.
60.5365a(i): (i) Except as provided in §60.5365a(i)(2), the collection of fugitive emissions components at a **well site**, **as defined in §60.5430a**, is an affected facility.

(1) [Reserved]

(2) A well site that only contains one or more wellheads is not an affected facility under this subpart. The affected facility status of a separate tank battery surface site has no effect on the affected facility status of a well site that only contains one or more wellheads.

(3) For purposes of §60.5397a, a "modification" to a well site occurs when:

(i) A new well is drilled at an existing well site;

(ii) A well at an existing well site is hydraulically fractured; or

(iii) A well at an existing well site is hydraulically refractured.

60.5430a Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. **For purposes of the fugitive emissions standards at §60.5397a, well site also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries)**

Answer: Thank you for the additional questions regarding salt water disposal wells. While we have answered your questions below, we want to stress that these responses are for guidance purposes only and do not constitute a formal applicability determination. If you have site-specific questions regarding applicability, please reach out to your regional contact. If you do not know who that is, we can provide that contact information to you.

You asked if salt water disposal wells are subject to fugitive emissions monitoring under OOOOa. Yes, salt water disposal wells are subject to OOOOa fugitive emissions monitoring. Well is defined at 60.5430a as "a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected." Further, the definition of a well site includes injection wells (see 60.5430a, "Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well").

Additionally, you asked if salt water disposal wells are subject to storage vessel requirements. Storage vessels containing salt water are potentially subject, depending on a lot of factors. One such factor is the potential VOC emissions from the tank. Some storage vessels are subject to closed vent system and control requirements, while others are not (see 60.5395a). There is a specific exemption from the storage vessel affected facility requirements for vessels that have a capacity greater than 100,000 gallons that are used to recycle water that has been passed through two stage separation (see 60.5365a(e)(5)). Further, fugitive emissions monitoring is required for "storage vessels" in specific cases (see 60.5430a definition of fugitive emissions components and 60.5430a for the definition of storage vessel) (i.e., the vessel stores crude oil, condensate, intermediate hydrocarbon liquids, or produced water). We would need additional information to determine if a specific storage vessel is subject to requirements and would refer you to your regional contact for such a determination.

Finally, we cannot comment on your additional scenarios at this time. If there is a specific site that you would like to discuss in terms of applicability, we request that you send that site-specific information to your regional contact for a formal applicability determination.

Question: Is there an exemption for fugitive emissions monitoring on sour gas storage vessels equipped with an external tank gauge?

Answer: I've been looking into the question you had regarding external tank gauges on sour gas wells. I wanted to provide some guidance to you but want to also recommend that if you have a specific site with questions, it might be best to reach out to the region for a more formal applicability determination. This information here is just guidance at this point.

Based on our conversation, you have some clients with sour gas well sites. At those sites, they use an external tank gauge that consists of a weighted cable that goes through the roof of the tank. There is a pinhole in the tank around the cable where fugitive emissions can escape but there is not a way to repair this hole and have the cable function as intended.

There are 3 types of storage vessels with different requirements under NSPS OOOOa.

1. Uncontrolled or atmospheric storage vessels with potential VOC emissions less than 4 tpy. These vessels are not subject to any control requirements or fugitive emissions monitoring in NSPS OOOOa.
2. Controlled storage vessels with potential VOC emissions greater than 4 tpy. These vessels are considered storage vessel affected facilities and are subject to control requirements in 60.5395a. These storage vessels are not subject to fugitive emissions monitoring in NSPS OOOOa.
3. Controlled storage vessels with potential VOC emissions less than 4 tpy. These vessels are exempt from the storage vessel requirements in 60.5395a. However, these storage vessels are subject to fugitive emissions monitoring.

I'm including some relevant rule text below. Please let me know if you have any additional questions. Again, if you need something formal related to a specific site, you should reach out to the region directly. I can provide that contact information if needed.

60.5365a(e) Each storage vessel affected facility, which is a single storage vessel with the potential for VOC emissions equal to or greater than 6 tpy as determined according to this section. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in this subsection. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a federal, state, local, or tribal authority.

60.5430a *Fugitive emissions component* means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to 60.5411a, thief hatches or other openings on a controlled storage vessel not subject to 60.5395a, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pneumatic pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

Question: I am hoping you can provide some guidance as to what is classified as a "new well drilled at an existing site" for purposes of determining fugitive emission monitoring applicability for well sites.

If a well is currently being used as an SWD well (well was drilled prior to 9/18/15) but then gets converted to an oil well in 2017, does this constitute a new well? The surface location is the same, but a new zone must be drilled in order for the well to be converted to an oil well. And, I am assuming there would be no hydraulic fracturing or refracturing.

After reading the definition of "well" under OOOOa, my gut says that the above scenario would be more of a well recompletion than a new well, therefore, no fugitive emission monitoring, but wanted to verify.

I just wanted to send you a quick summary on the overall process of converting an SWI well to a producer in the state of Louisiana.

- Operator analyzes "zones" within existing wellbore and makes determination is well could be a viable producing well
- Operator then contacts state on converting said well to producer. State representatives run tests on well to verify if well could be a producer
- If yes, operator then submits downhole permit application showing proposed work on conversion process and seeks approval from DNR
- Physical process of converting said well to producer involves some type of rig activity with supply vessels
- No compression, storage, or separation equipment is added to convert the well to producing
- It receives a new serial number due to the fact the two different departments are looking at producing wells vs SWI wells.

It's an existing well/wellbore converted to a different use. It's not a "new" or fracked well.

Answer: Thanks for sending over your question and additional information regarding what is classified as a "new well drill at an existing source". Below is some guidance to assist you but I want to stress that this is not a formal applicability determination. If you should need such a determination, you should reach out to your regional contact with site-specific information. If you do not know who to contact at the region, I can provide that information to you.

Modification is defined in general terms in the General Provisions of 40 CFR part 60 (60.2) as "any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any pollutant (to which a standard applies) into the atmosphere not previously emitted". In the preamble to the final NSPS OOOOa, we state, "The EPA believes the addition of a new well or the hydraulically fracturing or refracturing of an existing well will increase emissions from the well site for the following reasons. These events are followed by production from these wells which generate additional emissions at the well sites. Some of these additional emissions will pass through leaking fugitive emission components at the well sites (in addition to the emissions already leaking from those components)." (see 81 FR 35881).

In the scenario you described, a new zone is being drilled in order to convert a salt water disposal well into an oil well (physical change). Additionally, changing the operation of the well from an injection well to a producing well would result in an increase in emissions. Therefore, this could constitute a well site modification in terms of drilling a new well at an existing well site.

Question: These tanks and facilities were constructed after 9/18/2015, have uncontrolled emissions >6 tpy and therefore are controlled to meet OOOOa emission limits. Therefore, they have closed vent systems from the tanks to control device. Also, the external gauges are operating as intended. They do have a hole in the top of the tank, that if plugged, the gauge would not function as intended.

So our question is: External tank gauge was installed for safety purposes (so field personnel does not have to be on top of tanks and handle sour liquids) but a function of the gauge is that it vents. The tank is required to have a "leak free" closed vent system because the emissions are controlled per OOOOa. Do we have to consider the gauge vent a leak of the closed vent system since that is the intended function?

Answer: Based on the information you provided and some internal discussions, we would like to provide some guidance on a possible exemption for these sour gas storage vessel external tank gauges. You stated that these vessels are subject to the cover and control requirements in 60.5411a. Since the hole is located on the cover of the tank, you may wish to explore if one of the exemptions at 60.5411a(b)(2) might be applicable for these gauges.

The requirements in 60.5411a(b)(2) are that "each cover opening shall be secured in a closed, sealed position (e.g., covered by a gasketed lid of cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening." Further, 60.5411a(b)(2)(ii) allows the cover opening to not be sealed when it is required to "inspect or sample the material in the unit." We suggest that you work with the appropriate delegated authority to determine if your tank gauges are used for the purpose of inspecting the material in the storage vessel and would fall under this exemption.

Please note that this is only guidance and does not represent a formal applicability determination. If you would like a formal applicability determination, you should reach out to your state or region and present them with justification to support the use of the tank gauges as a means to inspect the material in the tank. If you do not know who the contact is for your region, I can provide that to you.

Question: I need to confirm if methane and VOC are included in LDAR at natural gas processing plants. It looks to me like it does. The company is required to follow the procedures in VVa, but must monitor components in methane and VOC service.

§60.5410a(f) For affected facilities at onshore natural gas processing plants, initial compliance with the methane and VOC standards is demonstrated if you are in compliance with the requirements of §60.5400a.

§60.5400a What equipment leak GHG and VOC standards apply to affected facilities at an onshore natural gas processing plant?

This section applies to the group of all equipment, except compressors, within a process unit.

(a) You must comply with the requirements of §§60.482-1a(a), (b), and (d), 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in §60.5401a.

Answer: Only equipment that is in VOC service or wet gas service is subject to §60.5400a. Subpart OOOOa does not require non-VOC-service equipment to be included in the LDAR program at onshore natural gas processing plants.

The affected facility for gas plants is the group of all equipment within a process unit (see 40 CFR 60.5365a(f)). "Equipment" is defined:

"as used in the standards and requirements in this subpart relative to the equipment leaks of GHG (in the form of methane) and VOC from onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this subpart." (§60.5430a)

Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-93, E168-92, or E260-96 (incorporated by reference as specified in § 60.17) must be used. (see 40 CFR 60.5400a(f). This provision must be used instead of § 60.485a(d)(1)). "Field gas" is defined in §60.5430a as "feedstock gas entering the natural gas processing plant.

Please also see EPA's Response to Public Comments on the EPA's Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources. 40 CFR Part 60, Subpart OOOOa. May 2016. Chapter 8, Comment EPA-HQ-OAR-2010-0505-7062 [https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7632]):

"While we proposed to regulate equipment in VOC and methane service, we did not evaluate equipment in methane service which is not also in VOC service. We recognize that a more detailed analysis is needed to determine the emissions reductions and impacts for equipment that is not in VOC service, and currently we do not have that type of data. However, in the 2016 Oil and Natural Gas Information Collection Request (ICR) we will be soliciting information on equipment in methane service at natural gas processing plants. Pending an analysis of this information, the EPA may conclude that the standard should address equipment at natural processing plants that is not in VOC service and propose changes in future actions."

Question: Is OOOOa only for major sources? What the definition of major? .... So mom and pop oil production locations, meaning one well one tank can potentially be applicable to quad oa?

Answer: NSPS do not apply only to major sources. MACT standards (under part 63) typically apply to major sources of HAP (hazardous air pollutants) though there are some requirements for area sources as well. In Part 63, a major source is defined as a source with a potential to emit at least 10 tpy of any single HAP or 25 tpy of any combination of HAP. There are currently 187 HAP listed.

The NSPS applies to any new, reconstructed, or modified source as of September 18, 2015 (when talking about OOOOa), regardless of the amount of HAP emissions. NSPS focus on criteria pollutants such as ozone, CO, SO2, NOx, lead, and PM. VOC typically are considered a surrogate for ozone. These are common pollutants that affect human health on a national level.

Yes, there is the potential that these types of production sites would be applicable to standards under OOOOa. We issued a small entity compliance guide to help producers in such situations. I've [HYPERLINK "https://www.epa.gov/sites/production/files/2016-08/documents/2016-compliance-guide-oil-natural-gas-emissions.pdf"] it here for your reference.

Question: Specific to fugitive emission components at a wellsite, I want to know which facility in the following scenario would be applicable assuming each is new or modified after 9/18/15, or would both be applicable:

a. Facility A: remote wellhead and separator, where production is separated, metered, commingled back together and piped to a centralized tank battery
b. Facility B: Centralized tanks battery that processes total production from Facility A

Answer: In this case, both facilities would be applicable to the fugitive emissions standards at §60.5397a.

The definition of "well site" at §60.5430a is intended to include well sites at natural gas storage sites.

§60.5430a: Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For purposes of the fugitive emissions standards at §60.5397a, well site also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries).

Question: A compressor station in the boosting and gathering segment is located in close proximity (i.e. the surface pads are physically adjacent) to a wellpad that it services. The same legal entity owns both the wellpad and the compressor station.

The well site is 'modified', per the OOOOa LDAR definition, so the well site is now subject to OOOOa LDAR. Is the compressor station part of the 'well site' for LDAR purposes?

I am unsure, based on the definitions of 'well site' and 'surface site'. The definition of 'well site' also specifically calls out centralized tank batteries, but nothing else off-site. The responses to comments also focus on centralized tank batteries.

In response to comments, EPA said: "*We are also further clarifying the boundaries of a well site for purposes of the fugitive monitoring requirements. Our intent is to limit the oil and natural gas production segment up to the point of custody transfer to an oil and natural gas mainline pipeline (including transmission pipelines) or a natural gas processing plant*."

Can you offer some guidance on this scenario?

Answer: I am happy to provide you with the following guidance. Please note that this is not a formal determination of applicability for any specific source or scenario. If you would like to receive a formal response, I can help you get in contact the appropriate state or regional people.

To help provide you with an answer, I am taking as a "given" your determination that you have a compressor affected facility (see §60.5365(c)) and a wellsite which is "modified" in accordance with the fugitive emissions modification provisions of §60.5465a(i)(3).

You ask if the "modification" to the wellsite will subject the compressor affected facility to the standards for fugitive emissions at a well site. The answer is "no". Compressor affected facilities do not include compressors at wellsites. Therefore, if your determination that the compressor is a "compressor affected facility" is correct (you state it is in the gathering and boosting segment), then it cannot be located at a wellsite. Therefore it is not part of the "collection of fugitive emissions" at a wellsite.

Compressors which are located at wellsites and ***which are not compressor affected facilities*** would be subject to the standards for fugitive emissions at a wellsite (if the applicability date is met).

Control Requirements

Question: Please confirm that flares meeting 60.18 are not "combustion devices" as that term is used in 60.5412a(d)(1). Flares are not specifically listed in the examples provided for "combustion devices". Additionally, flares are addressed in their own paragraph 60.5412a(d)(3).

Also, I wanted to verify a citation in the preamble to the rule where there may be a typographical error. On page 35869, the following language appears: "We added language to § 60.5412(d) and §60.5412a(d) to make our intent clear that flares are acceptable control devices for storage vessels and to identify the design requirements for flares. We also revised language in §60.5415a(b)(2)(vii) to clearly identify the continuing compliance requirements for flares."

However, 60.5415a(b)(2)(vii) is only applicable to centrifugal compressors. Did EPA intend to cite paragraph 60.5415a**(e)(3)** for flares controlling storage vessels? Which in turn references 60.5412a(d)(3) requiring flare design per 60.18(b) and Method 22 "compliance demonstration"?

Assumed that the "compliance demonstration" referenced in 60.5412a(d)(3) is an initial compliance demonstration as the rule does not specify that flares controlling storage vessels perform monthly Method 22 evaluations. The only other use of the term "compliance demonstration" appears in 60.5413a(a)(1) also relating to flares meeting 60.18.

If this interpretation is not correct, would appreciate the citation applicable to storage vessel affected facilities requiring monthly Method 22.

Answer: Flares are combustion devices. They are not enclosed combustion devices, so they would not have to meet the requirements for enclosed combustion device, e.g. maintained leak free. The only requirements for flares in 5412a(d)(1) would be monthly VE testing and continuous burning pilot.

We intended to revise 60.5415a(b)(2)(vii). We understand that this is for flares on centrifugal compressors. In the proposal, it was unclear what the continuing compliance requirements for those flares were.

Flares are a combustion device and have to meet the requirements of 60.5412a(d)(1). Also, see 60.5417a(h).

Question: Below is a brief description and a plot plan of the Amine skid. Sour gas is transported via pipe from 2 well pads (probably within a mile at most .. greater than a ¼ mile) .. definitely a separate pad location ..... normal or undisturbed foliage between pads. **Note:** separate permit from well pads as well.

Questions: Or My opinion:

1) It is not a gas plant by definition (does not separate NGL's) or a sweetening unit at a onshore NGPP.

2) It is not a compressor station

3) It is a sweetening unit which is exempt unless associated with a gas plant 60.5395(a)(f)&(g) ...... unless the sweetening unit is on a well pad

4) Is it exempt from OOOOa? If not, is it under 60.5397(a) .....

5) Guess I was wondering how do you handle or regulate stand alone sweetening units not on a well pad? NOTE: I have called several other upstream contacts ... nobody else has come across this.

Amine Plant processes up to 4.30 Million Standard Cubic Feet per Day (MMscfd) of natural gas on an annual average basis. The inlet gas from the facility contains up to 1,286 parts per million (ppm) hydrogen sulfide (H2S). The Facility receives sour gas via a pipeline from 2 well production batteries. The 449 horsepower (hp) generator engine (GEN-1) provides power to the Facility. GEN-1 is controlled by an Air Fuel Ratio Control (AFRC) and Catalyst. Inlet gas is routed to the amine sweetening unit. Rich amine is sent to a flash tank where the liquid stream is routed to the stripper column. Gases from the stripper column are routed to a condenser. Gases from the condenser and flash tank are combined and routed to the process flare (FL-1). The amine sweetening unit is equipped with a 0.75 MMBtu/hr reboiler (RB-1).

Two CTB's .. sales gas from well production pads goes to a Amine skid on a separate pad ...... down the road .. assume over a quarter mile.

Question #1:

Central Tank Battery 1 ... Only 1 well at this time:

The Central Tank (CTB) will operate continuously (8,760 hours per year). The facility is requesting to handle up to 500 bbl per day of crude oil (BOPD), 2,300 bbl per day of produced water (BWPD) and 4 million standard cubic feet per day (MMscfd) of produced gas. The produced gas from the facility contains up to 1,000 parts per million (ppm) hydrogen sulfide (H2S). Production from the well enters the Facility through a three-phase inlet separator. From the initial stage of separation, the gas is sent through a gas scrubber and then to a sales pipeline. Oil/gas emulsion is sent to a 0.5 MMBtu/hr heater treater (HT-1) for final separation of the gas, oil and produced water.

Vapors from the heater treater are routed to the process flare (FL-1). Once the oil exits the heater treater, it is routed to an initial 500-bbl condensate tank (CTK-1) and then to three 500-bbl condensate sales oil tanks (CTK-2 – CTK-4). The sales oil tanks release oil for custody transfer via a LACT unit. All four oil tanks will be controlled by the process flare (FL-1). The produced water that is separated from the inlet separator is sent to two 500-bbl produced water tanks (WTK-1 – WTK-2). Produced water is pumped from the Facility via pipeline. During upset conditions, when the gas sales line is down, produced gas from the gas scrubber is routed to an on-site emergency flare (FL-2), as an alternate operating scenario (AOS). During the AOS, we will limit the volume of gas to the emergency flare to 125 Mscf/hr and 87.6 MMscf/yr. To be conservative, the sales gas line is assumed to be down up to 8% of the year.

Central Tank Battery #2: Only 1 well at this time

The CTB will operate continuously (8,760 hours per year). The facility is requesting to handle up to 300 bbl per day of crude oil (BOPD), 2,600 bbl per day of produced water (BWPD) and 2million standard cubic feet per day (MMscfd) of produced gas. The produced gas from the facility contains up to 3,500 parts per million (ppm) hydrogen sulfide (H_2S). Production from the well enters the Facility through a three-phase inlet separator. From the initial stage of separation, the gas is sent through a gas scrubber and then to a sales pipeline. Oil/gas emulsion is sent to two 0.5 MMBtu/hr heater treaters (HT-1, HT-2) for final separation of the gas, oil and produced water. Vapors from the two heater treaters are routed to the process flare (FL-1). Once the oil exits the heater treaters, it is routed to an initial 500-bbl condensate tank (CTK-1) and then to five 500-bbl condensate sales oil tanks (CTK-2 – CTK-6). The sales oil tanks release oil for custody transfer via a LACT unit. All six oil tanks will be controlled by the process flare (FL-1). The produced water that is separated from the inlet separator is routed to a FWKO and is then sent to two 500-bbl produced water tanks (WTK-1 – WTK-2). Vapors from the FWKO are also routed to the process flare (FL-1). Produced water is pumped from the Facility via pipeline. During upset conditions, when the gas sales line is down, produced gas from the gas scrubber is routed to an on-site emergency flare (FL-2), as an alternate operating scenario (AOS). To be conservative, the sales gas line is assumed to be down 9% of the year (65.7 MMscf/yr).

Question #2) Only a generator for power ... and of course a flare...... they actually lease/rent the Amine skid.

Answer: Thank you for your 1/20/16 question about the "stand alone" amine skid, as well as the additional information that you sent on 01/04/17. As you have described the scenario, we agree there is neither a §60.5365a(f) nor (g) affected facility, since the amine skid is not located at a "natural gas processing plant". The collection of fugitive emissions on the skid would not be a §60.5365a(i) or (j) affected facility since it is not located at a wellsite or compressor station site. The rich amine storage tank would not be §60.5365(e) affected facility since it is not storing one of the four liquids which define a storage vessel (see §60.5430a).

That said, this is for guidance purposes only and not a formal determination of applicability for any specific site. There may be details of which we are not aware which would lead us to a different conclusion regarding whether the amine skid is part of the wellsite or a natural gas processing plant. If you want to receive a formal determination of applicability, I am happy to help you coordinate with the appropriate state or region.

Question: I'd like to clarify the reference to capital. The company is replacing dehydrator reboilers/burners with larger burners and adding fugitive piping components. These physical changes, i.e., larger burners and additional fugitive components will result in higher emission rates. Thus, it seems they are making a modification for NSPS purposes. …and in this case, there will also be an associated capital expenditure.

Question: Is the following a correct understanding? For quad O purposes, if there are physical changes that result in increased emission rates, but which do not involve capital expenditure, for Subpart OOOOa only, this is not considered to be a modification. However, for other NSPS subparts, the changes would be considered a modification unless explicitly stated otherwise in the subpart.

Answer: Modification is defined in the General Provisions under section 60.14. There, a modification is any physical or operational change to an existing facility which results in an increase in the emissions of any regulated pollutant to the atmosphere. However, paragraph (e)(2) of that section provides the exception related to capital expenditure.

Under OOOOa, modifications vary based on the type of affected facility (e.g., compressors, storage vessels, or fugitive emissions components). We explicitly state that for fugitives an increase in emissions doesn't necessarily trigger a modification when there is no capital expenditure. However, other affected facilities do not have this exemption based on capital expenditure.

I hope this helps answer your question. It's not a one-size approach towards modification within OOOOa.

Question: Can you provide some guidance as to whether a well site that has a dehydrator (to remove excess water) would be considered a process under the rule? My initial reaction is that this does not rise to the definition of process, but wanted to reach out for some guidance.

Understand the difference in process and process unit. So it appears I should focus on "routed to a process or route to a process" definition. So is it your experience that a dehydrator could be available as a process that could be vented to?

Answer: First of all, don't confuse "process" with "process unit" when reading the definitions.

"Routed to a process or route to a process is defined in section 60.5430a, and it should help you determine if a dehydrator meets that definition for purposes of determining the presence of an available process at the well site.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process that is operational where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Once you've digested the above definition, then consider whether a dehydrator at a well site could qualify as an available process.

Question: Regarding the initial compliance period under OOOO (60.5410) and OOOOa (60.5410a), what is the definition of "initial startup" for a natural gas well when determining when an initial compliance period begins? Let me know if you have any questions or need clarification. Thanks!

Answer: Both OOOO and OOOOa do not have a blanket definition for "initial startup". Rather, it is carved out in each individual segment of the rule e.g., well completions, pumps, etc.. For the well completion requirements initial startup is the beginning of flowback (e.g. must route flowback to well completion vessel … etc). Startup of production (**which is different**) means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water. It is linked back to 60.5375 and 60.5375a.

See section 3.0 on well completions (page 17): [HYPERLINK "https://www.epa.gov/sites/production/files/2016-08/documents/2016-compliance-guide-oil-natural-gas-emissions.pdf"]

Question: I've got a few more questions based on the proposed scenarios listed below:

1. At day 1, the flash rate may be close to a point where emissions would leak from the tanks. Within the first 60 days, the rates drop to a point where calculations show no emissions leak from tank hatches. Would this production decline and resulting drop in emissions satisfy the 95% reduction in emissions as outlined in section 60.5395a?
    a. From a certification perspective, we could measure the peak rate of production, and then calculate emissions at day 60 to determine if there was any potential for leakage.
2. If a choke management strategy is used to bring wells online slowly, the peak production rate may be at day 45. Should we continue to use the maximum daily rate for the first 30 days or use the maximum expected rate at day 45?
3. If the client is unsure of their expected production rate due to utilization of different completion practices, they will measure the first 30 days of production and report back rates. At this point, do I certify the maximum rate going forward or the maximum during the 30 day period that passed?
    a. From that perspective, the maximum rate for the future will be at day 31.

Answer:

At day 1, the flash rate may be close to a point where emissions would leak from the tanks. Within the first 60 days, the rates drop to a point where calculations show no emissions leak from tank hatches. Would this production decline and resulting drop in emissions satisfy the 95% reduction in emissions as outlined in section 60.5395a? First, we are referring to working, breathing, and flashing losses when looking at emissions from storage vessel affected facilities, not leaks. No, the decline in production does not qualify as 95 percent control. If the vessel never emits more than 4 tpy, then it is not an affected facility (or subject to control). The determination must be made within 30 days of receiving fluids, so a decline after day 30 is not applicable to the determination of PTE.

    a. From a certification perspective, we could measure the peak rate of production, and then calculate emissions at day 60 to determine if there was any potential for leakage. The peak rate of flow to the vessel during the first 30 days would be your criteria to model PTE in order to determine whether controls are required.
2. If a choke management strategy is used to bring wells online slowly, the peak production rate may be at day 45. Should we continue to use the maximum daily rate for the first 30 days or use the maximum expected rate at day 45? The determination of PTE must be made in the first 30 days. The technique to determine potential, by definition, should account for variance in flow. If the storage vessel is found to emit greater than 6 tpy, the storage vessel is an affected facility, regardless of an initial determination that projected otherwise. The standard applies to an affected facility storage vessel. If the choke management strategy roughly described here resulted in an initial determination that the vessel was not an affected facility, but emissions after the initial determination indicate that the vessel is emitting greater than 6 tpy, then the storage vessel would become an affected facility subject to control at that later date. Since the determination is based on the PTE, an active flow management strategy would be incorporated into the determination. A "choke management strategy" could only be used to reduce potential emissions if it meets the criteria for enforceability, referred to in 60.5365a(e).
3. If the client is unsure of their expected production rate due to utilization of different completion practices, they will measure the first 30 days of production and report back rates. At this point, do I certify the maximum rate going forward or the maximum during the 30 day period that passed?
    a. From that perspective, the maximum rate for the future will be at day 31. Same answer as above. The determination must be made in the first 30 days. The technique to determine potential emissions should, by definition, account for variance in the flow. If the storage vessel is found to have a PTE greater than 6 tpy, the storage vessel is an affected facility and subject to control, regardless of an initial determination

Question: How to 'distribute' emissions from storage vessels that are manifolded by liquid flow line.

As example: PTE from production of the oil well is 4 tpy. The tank battery consists of two oil storage vessels, manifolded by liquid flow line. The normal operating practice is production from the well is routed from one vessel to the other when a load is truck hauled away, but there are many variables that affect that 'normal operating practice'.

So, my question is how to define individual storage vessel PTE? In this example, 2 tpy to each vessel of the TB?

I suspect guidance has been issued but I am unfortunately unable to locate it, so if appropriate please direct me to it.

Answer: I'm not sure in which states you are operating but we do understand that Colorado considers the PTE from the entire tank battery, which is what you are describing below in your question. We did not take that approach with OOOO or OOOOa. Instead, PTE should be calculated on a per tank basis since the affected facility is each individual storage vessel, not a collection of storage vessels in a tank battery. In your example, the first tank would likely have a higher PTE than the second tank because gases are going to be higher initially.

Question: We are trying to determine the "*maximum average daily throughput determined for a 30 day period of production*." Some of my colleagues feel that this is the maximum 30 day average of production and others interpret this as the maximum daily production rate in the first 30 day period.

In any case, the rate in question could be very significant due to steep production decline curves that we see. Another added source of confusion is a strategy of bringing wells online slowly that would result in the maximum production rates occurring in the second or third month of production.

Answer: Thank you for sending over your question. The interpretation that we intended was the latter, the maximum daily production rate in the first 30 day period. Please let me know if you have any additional questions.

Recordkeeping & Reporting

Question: When is the first OOOOa annual report due?

Answer: The first annual report is due no later than 90 days after the end of the initial compliance period. The initial compliance period begins on August 2, 2016, or upon initial startup, whichever is later, and ends no later than 1 year after the initial startup date for your affected facility or no later than 1 year after August 2, 2016. The initial compliance period may be less than one full year.

Question: In the reporting requirements in 5420a(b), the annual report should include the US well ID, as applicable. I may be over thinking this, but the US well ID would obviously apply to the well affected facilities, but would it apply elsewhere? I don't think it would apply to compressors, tanks, pumps, pneumatic controllers, natural gas processing plants, or sweetening units since those are equipment specific, but what about fugitive emission components at wellsites? If so, do you identify every US well ID associated with the facility? This list has the potential to get quite lengthy.

Answer: There are three potential scenarios for reporting the US well ID under 60.5420a(b).

1. If you have a well site that contains one or more wells, and they are affected facilities under NSPS OOOOa, then you would report the US well IDs for the wells which are affected facilities in that report.

2. If you have a well site that contains fugitive emissions components that are an affected facility under NSPS OOOOa, then you would report the US well IDs that are associated with the fugitive emissions components located at that well site.
3. If you have a well site that contains other affected facilities under NSPS OOOOa, including, but not limited to pneumatic pumps, pneumatic controllers, or storage vessels, then you would report the US well IDs for any wells associated with that affect facility. For example, if you have a storage vessel located at a well site with 3 wells but only 1 well sends fluids to that storage vessel, then you would only report the US well ID for the well that sends fluids to that storage vessel when reporting information for the storage vessel affected facility.

Question:

Answer:

Question:

Answer:

Question:

Answer:

Monitoring

Question: I was hoping you could help me out with a question regarding NSPS OOOOa and scheduling LDAR inspections.

Below is some correspondence between a consultant of mine and Alexis North with EPA region 8 regarding the length of time between LDAR inspections.

My field supervisor emailed me a scenario for his LDAR inspections.

Here was the scenario:
1st required inspection date: 4-28-2017
2nd inspection date: 9-27-2017 (152 days after the 1st inspection date)(meets the semi-annually at least 4 months apart requirement).

3rd inspection date: 4-28-2018 (213 days after the 2nd inspection date, which is 6 months and 33 days)
4th inspection date: 9-27-2018 (152 days after the previous inspection date)

The way my consultant and Region 8 interpreted the rule was that the 6 month 33 day period puts us out of compliance for the planned inspection on 4-28-2017.

Another take on this scenario was that semiannually should mean twice per year, so we should be able to do one survey in January and another in October and still satisfy the rule.

Can you help us interpret the rule so we can schedule our inspections and be in compliance?

Answer: Thanks for your email.

The information from your consultant and Alex North in Region 8 is correct. Once the initial survey under 60.5397a of Subpart OOOOa is conducted, the clock starts and the next semi-annual inspection would be due within six months. Semi-annual inspections must be at least four months apart, but no more than six months apart.

I would like to clarify, additionally, that while you may choose to perform your initial survey on April 28, 2017, you are not required to complete the initial survey until June 3, 2017. The initial compliance for fugitive emissions program (only) is determined as follows in 60.5397a:

60.5397a(f)(1) You must conduct an initial monitoring survey within 60 days of the startup of production, as defined in 60.5430a, for each collection of fugitive emissions components at a new well site or by June 3, 2017, whichever is later. For a modified collection of fugitive emissions components at a well site, the initial monitoring survey must be conducted within 60 days of the first day of production for each collection of fugitive emission components after the modification or by June 3, 2017, whichever is later.

(f)(2) You must conduct an initial monitoring survey within 60 days of the startup of a new compressor station for each new collection of fugitive emissions components at the new compressor station of by June 3, 2017, whichever is later. For a modified collection of fugitive components at a compressor station, the initial monitoring survey must be conducted within 60 days of the modification or by June 3, 2017, whichever is later.

For your specific case, you have listed April 28, 2017 as the required date for the first inspection. However, per the text provided above, the initial monitoring survey must be conducted by June 3, 2017. If you choose to still complete the initial survey in April, you must conduct subsequent surveys within 6 months of that date, but not sooner than 4 months of that date.

I hope this helps. Please let me know if you have any additional questions on this topic.

Question:

- Self-certification general questions
- 60.51413(d)(2) Test fuel with propene
- 60.5413(b)(11) PT criteria – excess combustion air greater than 150%
- 60.5413(e) continuous compliance pilot flame must be present at all time

Answer:

As I stated in my voicemail, Amy Hambrick asked me to touch base with you concerning the manufacturer tests for enclosed combustors for the Oil and Gas rule. The program is run out of the EPA's Office of Enforcement and Compliance Assurance, and Marcia Mia is the lead for the program. I assist Marcia with testing issues related to the program.

To answer some of your specific questions that Amy passed along, we do require that testing be performed with propene. Although we know that most field gas is unlikely to contain propene, field gas can have a variety of compounds. When we developed the program, we determined that due to the range of possible compounds, it was necessary to challenge the combustors during a manufacturer performed test, as it was intended to be a one-time test for many units, and as such, the unit could be used on a variety of different field gases. The use of propene ensures the unit will be able to achieve good combustion of a variety of VOCs. Additionally, we do require a continuous pilot flame at all times of operation. This requirement is actually not unique to manufacturer tested units. It applies to all enclosed combustors and flares. Also, the excess combustion air during the test is required to be greater than 150%. I am not exactly sure of the genesis of this requirement, but I suspect it was added to ensure that the unit achieves complete combustion.

For your reference, I have attached our enclosed combustor testing guidance document. Because this test serves as the performance test for many units, we are very strict on the testing quality and documentation. Please feel free to contact Marcia or me with any questions you may have.